Effect of Ramping Requirement and Price Cap on Energy Price in a System with High Wind Penetration

S. Martin[1,2]

Universidad de Málaga
Málaga, Spain

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[1] UMA, Universidad de Málaga, Málaga, Spain.

[2] These notes are based on joint work with Yves Smeers (CORE, UCL, Belgium) and J. A. Aguado (UMA). Errors and shortcomings in this presentation are mine.

Outline

Introduction

Context

- European power market is currently decommissioning and mothballing considerable conventional generation capacity.
- Subsidized zero marginal cost renewable units increase their share in the generation mix and decrease electricity prices.
- This makes conventional plants operating in this distorted “energy only” markets unable to recover their Fixed Operating and Maintenance costs (FOM).
- The plants taken off line are those with higher FOM, which in many cases are recent highly efficient and flexible Combined Cycle Gas Turbines (CCGT) and Open Cycle Gas Turbines (OCGT) units.
- The system is thus losing a significant amount of the flexible capability that is, or will be, necessary for dealing with variability and volatility of renewable generation.

Overall Question

- The market does not reveal the need for that flexibility, whether because of agents' myopia or policy distortions.
- Will the decommissioning continue without concern for needed flexibility service as long as existing capacity is sufficient to cover demand?
- Could the introduction of some additional flexibility products, at some stage, stop this trend?

REMARK: The proposed model is intended for exploring operation bounds and links among parameters, and not to get precise operation values.

Regarding Variability from Wind Generation

- The additional reserve requirement due to renewable resources integration is a contentious subject, that has been studied by many authors: Doherty et al 2005, Smith et al 2007, Tuohy et al 2009, Ortega-Vazquez et al 2009, Papavasiliou et al 2011.
- General consensus: an increase in variability leads to an increase in the required operational flexibility, in particular the ramping capability.
- This is true despite the fact that under certain conditions the flexibility already required for contingency and load following could suffice to cover the uncertainty due to forecasting error of intermittent renewable generation.
- Capacity for ramping flexibility adds to the one already necessary for frequency support to accommodate large fractions of wind power.

Literature Review on Flexible Ramp Capability Products

- Focus on proposals at Midcontinent Independent System Operator (MISO) and California Independent System Operator (CAISO).
- Definition:
  - N. Navid and G. Rosenwald, "Market solutions for managing ramp flexibility with high penetration of renewable resource," Sustainable Energy, IEEE Transactions on, vol. 3, no. 4, pp. 784–790, Oct 2012.
  - L. Xu and D. Thretheway, "Flexible Ramping Products Incorporating FMM and EIM. Revised Straw Proposal," CAISO Market Analysis and Development & Market and Infrastructure Policy, Tech. Rep., 13 Aug. 2014.
- Discussion:
  - B. Wang and B. F. Hobbs, "A flexible ramping product: can it help real- time dispatch markets approach the stochastic dispatch ideal?" Electric Power Systems Research, vol. 109, no. 0, pp. 128 – 140, 2014.
  - J. Ryan, E. Ela, D. Flynn, and M. O'Malley, "Variable generation, reserves, flexibility and policy interactions," in System Sciences (HICSS), 2014 47th Hawaii International Conference on, Jan 2014.

Focus of this Work

Observation: Perverse effect, penetration of variable generation increases the need for ramping capability at the same time as it lowers electricity prices to levels incompatible with the remuneration of the conventional plants that provide that flexibility.

Questions:

- We analyze the mothballing process and study how it is affected by a price cap implemented in the energy only market. The question we address is whether we need both energy and ramping product markets or whether a sole price cap is relevant.
- We test the robustness of the response to this question by verifying how it is affected by certain features of the market such as feed-in premium to wind, wind forecast, reserve requirement (estimation of the wind forecast error) and the agents risk aversion.

Methodology

Base Model

The proposed model is based on

S. Martin, Y. Smeers, and J. Aguado, "A stochastic two settlement equilibrium model for electricity markets with wind generation," Power Systems, IEEE Transactions on, vol. 30, no. 1, pp. 233-245, 2015.

but with significant differences. It is posed as a two stage risk averse stochastic program that embeds all agents of the system (producers, consumers and TSO) in a single entity.

Market Model

- Agents: Generators, Transmission System Operator (TSO), and consumers (price responsive or fixed demand).
- Two settlements: Day-Ahead and Real Time.
- Two stage risk averse stochastic program.
- Agents are price takers in both settlements $\Rightarrow$ the model can be solved by maximizing a risk adjusted global welfare computed over all agents.
- Wind forecast is the only source of uncertainty considered and it is modeled through an scenario tree.
- Models include ramping products and ramping constraints.
- The "system" is risk averse, and it uses a linear combination of the expectation and the Conditional Value at Risk (CVaR) of the balancing cost as a risk measure.
- All constraints are linear.

Two Settlements

Day-Ahead:

- Clearing of the energy market by the Power eXchange (PX), and the commitment of capacity for reserves and ramping products.
- Variables: Demand (in case of price responsive), generation from wind turbines and conventional generators, capacity for reserves, and capacity for ramping products.

Real Time:

- Balancing is the only real time activity. The balancing mechanism uses the energy from reserves (upward or downward) and ramping products to solve deviations. The energy and capacities are paid at opportunity cost as implicitly computed by the optimization model. In case of wind shortage, wind turbines have to pay for the additional energy required to fulfill their delivery. In case of wind surplus, wind turbines can spill part or all of the surplus, or offer it to the market and use the reserves to accommodate that surplus.
- Variables: Energy deployed from reserves and/or ramping products.

Model for Generators

Only two types of generators are considered, conventional generators and wind turbines, and it is assumed that a single firm owns all the generators.

Conventional generators:

- Linear variable cost.
- Upper and lower capacity bounds.
- Bounds for their upward and downward ramping capability.

A price cap is modeled by introducing a conventional generator with a high generation cost and “infinite” capacity.

Wind turbines:

- Zero marginal generation cost.
- Zero lower bound for generation.
- Upper generation bound given by a scenario tree.
- Receive a feed-in premium on the energy price in day-ahead.

TSO and Consumers Models

Transmission System operator:

- Rules the balancing mechanism and sets the requirements for reserve capacities (upward and downward) and ramping products.
- Here the constraints for reserve requirements are adapted from the Spanish Grid Code.

Consumers: We consider two models for consumers

- Price responsive model using a linear inverse demand function, in which case the objective function is quadratic.
- Fixed demand, in which case the objective function is linear.

MISO's Proposal (I)

N. Navid, "Multi-Faceted Solution for Managing Flexibility with High Penetration of Renewable Resources," in FERC Technical Conference Increasing RT & DA Market Efficiency Through Improved Software, 24-26Jun. 2013.

Overall idea: Commit ramp capability well in advance (in day-ahead) to increase the scheduled operational flexibility of the system (in real time), with the intent of avoiding expensive fast units for providing that flexibility.

Remarkable features:

- Only dispatchable generators can provide ramping products.
- They add to the needs for existing energy and ancillary services, which remain unchanged.
- Use a demand curve for the committed capacity (a flat curve is proposed) and a market clearing price for the energy from these products.
- As a principle, these products should be priced at resource opportunity cost. But they propose to use day-ahead prices.

MISO's Proposal (II)

- The requirement for ramping products at period t is determined by the expected variability of the net demand at period $t+2$ within a certain confidence level.
- Committed ramp capability at period t must be sufficient to allow the system to go from the demand d_t, at period t, to any value in the variability range $[\overline{d}_{t+2} - K_d\sigma_{d,t+2}, \overline{d}_{t+2} + K_u\sigma_{d,t+2}]$ at period $t+2$.
- $\overline{d}_{t+2}$ is the expected demand at period $t+2$, and $\sigma_{d,t+2}$ is the forecast of standard deviation for demand at period $t+2$.
- K_u, K_d are constants that depend on the confidence level. Values $K_u = K_d = 2.5$ are suggested by Nivad. They correspond to a confidence level of approximately 90%, assuming a normal distribution for demand.

Ramping Products in Our Model

Coincidences with MISO proposal:

- Only dispatchable generators can supply ramping products.
- Ramping products are committed in day-ahead and deployed in real time.
- Required amount of ramping products.

Differences with MISO proposal:

- In our model the energy from these products is remunerated at opportunity cost in real time, this differs from MISO's initial proposal that supposes that they are priced at day-ahead cost.
- In our model, capacity reserved for ramping products is remunerated at opportunity cost as implicit in the optimization problem, instead of using a demand curve as proposed at MISO.

In short, we assume the pricing of both energy and capacity in ramping products to be at opportunity cost.

Mothballing: Description and Assumptions

Assumptions:

- Progressive retirement of the conventional plants.
- Criterion: Dismantling occurs when the margin that they make on energy and services is lower than their fixed operation and maintenance cost (FOM).
- Dismantling stops when all active plants cover their FOM.
- The margins of the dispatchable units and their FOM are calculated over a period of one year using only four representative days.
- Wind is represented by four wind days (24 periods of one hour in each day). These patterns come from the clustering of historical data for wind in the Spanish System in 2012.

Mothballing Algorithm

Mothballing is modeled as an iterative process summarized as follows:

1. Start with all dispatchable generators.
2. Solve the optimization problem and calculate the margins for all dispatchable generators in the system, except for the back-up generator, that is never mothballed.
3. The dispatchable generator with the lowest negative value of margin is mothballed.
4. Solve the optimization problem with the remaining generators in the system and recalculate the margin for each dispatchable generator still in the system.
5. If the margin is greater of equal than zero for all the dispatchable generators in the system, the mothballing process stops at this point; in other case we go to step 3).

Uncertainty Modeling

- We consider only uncertainty from wind generation.
- A whole year is represented by only four representative days, based on historical data for the Spanish system in 2012 (from the Spanish TSO).
- Each day consists of 24 values equal to the expected wind for each hour in that day.
- In order to take into account the wind forecast error, 12 scenarios are considered for each hour, assuming the values in an hour t for a day ξ fit a beta distribution (Bofinger et al 2002, Fabri et al 2005), with average $\mu_{\xi,t}$ and standard deviation $\sigma_{\xi,t} = 0.2\mu_{\xi,t} + 0.02$ in per unit values (Ortega-Vazquez et al, 2009).
- The total number of scenarios is $4 \times 24 \times 12$, 4 wind days, 24 periods per day and 12 scenarios for each period.

Mathematical Approach

Set of Constraints

- Capacity bounds for dispatchable generators.
- Capacity bounds for wind turbines.
- Balancing equations.
- Ramping constraints.
- Reserve requirement constraints.
- Ramping product requirement constraints.
- Conditional Value at Risk Constraints.

Objective Function

- Consumers welfare (in case of price responsive demand).
- Incomes from Feed-in Premium to wind generation.
- Generation cost of dispatchable generators.
- Expected value of balancing cost.
- CVaR of the balancing cost.

Case Study

Summary of the Test Cases

Table : Summary of the test cases

	Demand	Backup gen. (€/MWh)
Ramping products	Price Responsive	-
	Fixed demand	100, 300, 563.8, 1000
No ramping products	Price Responsive	-
	Fixed demand	100, 300, 563.8, 1000

Summary of generators' data

N	Tech.	$\overline{X}_g$ (MW)	$\overline{R}_g = \underline{R}_g$ %/h of $\overline{X}_g$	cg_g (€/MWh)	FOM*
1	CCGT	2910.81	53.33	46.90	80.00
2	CCGT	1550.05	53.33	46.47	79.00
3	CCGT	1584.44	53.33	46.04	78.00
4	CCGT	3863.34	53.33	45.61	77.00
5	CCGT	5588.25	53.33	45.17	76.00
6	CCGT	2744.32	53.33	44.74	75.00
7	CCGT	3274.98	53.33	44.31	74.00
8	CCGT	2056.58	53.33	43.88	73.00
9	CCGT	2153.50	53.33	43.45	72.00
10	Nuclear	1519.23	2.08	10.91	269.95
11	Nuclear	6053.35	2.08	10.29	264.66
12	Coal	2035.89	20.00	37.50	100.00
13	Coal	5119.13	25.00	38.44	98.00
14	Coal	1198.12	25.00	19.77	97.00
15	Coal	1945.51	25.00	20.24	95.00
16	Bac. gen.	30000.00	50.00	Price cap	0.00
17	Wind	22573.00	0.00	0.00	0.00

*Fixed Operation and Maintenance Cost (€/(MW·day)).

Mothballing with and without ramping products

The system starts with an initial dispatchable capacity of 43.6 GW. Values in the table corresponds to the end state.

	Gen. GW	Price cap	ξ (Wind day) 1	 2	 3	 4	Aver.
μ_ξ (%)*			5.8	22.2	47.1	61.2	
Pr^ξ (%)			13.3	73.2	6.8	6.7	
		Energy price (€/MWh)					
FD-RP	28.1	100.0	82.9	74.2	37.9	30.6	69.9
FD-RP	28.1	300.0	221.8	186.6	37.9	30.6	170.7
FD-RP	33.7	1000.0	96.3	43.4	37.9	30.5	49.2
FD-RP	33.7	563.8	72.8	43.4	37.9	30.5	46.0
PR-RP	28.1	-	55.1	49.0	38.7	32.2	48.0
FD-NRP	28.1	100.0	82.4	74.8	42.0	41.7	71.4
FD-NRP	28.1	300.0	221.4	191.2	42.0	41.7	175.1
FD-NRP	33.7	1000.0	95.8	42.9	42.0	41.7	49.8
FD-NRP	33.7	563.8	72.3	42.9	42.0	41.7	46.7
PR-NRP	28.1	-	55.1	49.0	38.7	32.2	48.0

* Over the wind power installed, FD = fixed demand, RP = with ramping products, PR = price responsive, NRP = No ramping products.

First Mechanism

- The backup generator is only used for ancillary services in balancing but not in the day-ahead energy market.
- There is curtailment in supply in real time but it is not due to a shortage of capacity in the day-ahead market but to a lack of ramping or reserve capacity in real time.

In other words, there is enough generating capacity but not enough flexibility. The price cap has two effects on the price of ancillary services:

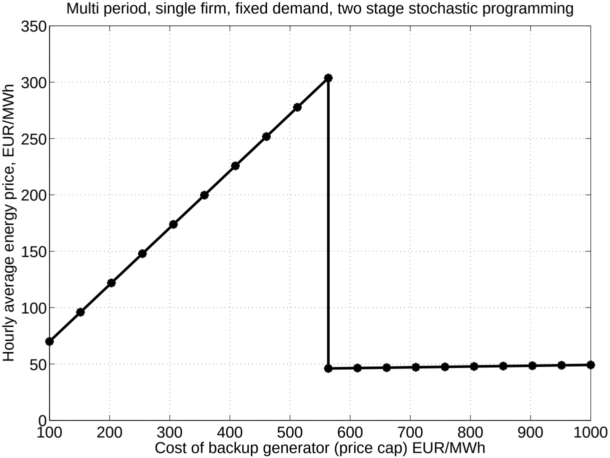
- As long as capacity constraints are not tight, generators only get additional revenue when they hit the reserve constraints. Dismantling continues as long there is not enough revenue coming from these constraints.
- Revenue from ancillary services increases when more reserve constraints are hit and the backup generator is used to satisfy them (that is when there is curtailment in that scenario). This global remuneration of the plants is usually lower than the price cap, since the backup generator is not usually used in all scenarios.

Second Mechanism

- In this case the backup generator supplies energy in day-ahead (that means a high energy price in day-ahead market).
- The day-ahead market clears at the price cap (some demand has to withdraw) in some hours and the energy price in those hours is equal to the price cap.
- This is a very costly solution.

Transition from Second Mechanism to First Mechanism

A high back up cost leads to a low energy price. The explanation is that the higher price cap reduces the number of hours of curtailment and it is better to pay a very high price only for a few hours than a high price in many hours.



Results for Several Configurations (I)

	Price cap (€/MWh)	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)							
		Case 1		Case 2		Case 3		Case 4*	
μ_ξ (%) expec. wind		5.86	61.17	22.20	22.20	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) prem.		30.00	30.00	0.00	80.00	30.00	30.00	0.00	80.00
λ risk aversion		0.40	0.40	0.40	0.40	0.00	1.00	0.40	0.40
Energy demand in day-ahead (GWh)									
FD-RP		28.75	28.75	28.75	28.75	28.75	28.75	28.75	28.75
PR-RP		26.33	29.45	27.34	27.34	27.34	27.24	26.88	26.81
PR-NRP		28.58	27.19	28.55	28.73	28.74	28.41	28.57	28.60
Energy price in day-ahead (€/MWh)									
PR-RP	-	55.06	32.17	49.05	49.05	49.05	49.56	51.25	51.62
PR-NRP	-	44.29	39.71	43.24	42.33	42.28	43.93	43.18	43.04
FD-RP	100.00	82.89	30.58	74.20	74.19	72.33	77.39	77.30	78.28
FD-NRP	100.00	82.39	41.67	75.16	74.24	73.12	77.60	71.48	71.42
FD-RP	300.00	221.84	30.58	186.64	186.64	178.21	199.67	198.68	199.66
FD-NRP	300.00	221.37	41.67	191.55	190.63	185.58	199.88	174.52	174.46
FD-RP	1000.00	96.29	30.47	43.37	43.37	43.26	43.87	44.03	45.01
FD-NRP	1000.00	95.79	41.67	43.26	42.33	42.29	44.08	43.20	43.09
FD-RP	563.79	72.77	30.47	43.37	43.37	43.26	43.87	44.03	45.01
FD-NRP	563.79	72.26	41.67	43.26	42.33	42.29	44.08	43.20	43.09

FD = fixed demand, RP = with ramping products, PR = price responsive, NRP = No ramping products.

* For Case 4, $m_y = 0.60$, $m_x = 0.02$.

Results for Several Configurations (II)

	Price cap (€/MWh)	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)							
		Case 1		Case 2		Case 3		Case 4	
μ_ξ (%) expec. wind		5.86	61.17	22.20	22.20	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) prem.		30.00	30.00	0.00	80.00	30.00	30.00	0.00	80.00
λ risk aversion		0.40	0.40	0.40	0.40	0.00	1.00	0.40	0.40
Energy demand in day-ahead (GWh)									
FD-RP		28.75	28.75	28.75	28.75	28.75	28.75	28.75	28.75
PR-RP		26.33	29.45	27.34	27.34	27.34	27.24	26.88	26.81
PR-NRP		28.58	27.19	28.55	28.73	28.74	28.41	28.57	28.60
Total profit (M€/h) (wind + dispatchable)									
PR-RP	-	0.71	0.49	0.72	0.64	0.69	0.68	0.76	0.72
PR-NRP	-	0.41	0.65	0.51	0.47	0.47	0.51	0.57	0.32
FD-RP	100.00	1.41	0.43	1.41	1.33	1.32	1.48	1.46	1.45
FD-NRP	100.00	1.39	0.71	1.37	1.34	1.31	1.44	1.41	1.16
FD-RP	300.00	5.02	0.43	4.54	4.47	4.26	4.92	4.81	4.80
FD-NRP	300.00	4.98	0.71	4.54	4.50	4.37	4.78	4.47	4.22
FD-RP	1000.00	1.96	0.43	0.55	0.47	0.52	0.45	0.54	0.53
FD-NRP	1000.00	1.92	0.71	0.51	0.47	0.47	0.51	0.57	0.31
FD-RP	563.79	1.26	0.43	0.55	0.47	0.52	0.49	0.54	0.53
FD-NRP	563.79	1.23	0.71	0.51	0.47	0.47	0.51	0.57	0.31

FD = fixed demand, RP = with ramping products, PR = price responsive, NRP = No ramping products.

* For Case 4, $m_y = 0.60$, $m_x = 0.02$.

Conclusions

- Price cap has a high impact on dismantling process.
- Ramping products have almost no impact on dismantling, but they have a significant impact on lowering the energy prices in the case of fixed demand.

Answer to the initial questions:

- Regarding the dismantling process, a sole price cap is relevant.
- The results are robust respect to changes in: feed-in premium to wind, wind forecast, reserve requirement, estimation of the wind forecast error, and the agents risk aversion.

Thank You for Your Attention!